

March 10, 2010

Executive Secretary  
North Dakota Public Service Commission  
State Capitol Building  
Bismarck, ND 58505

Re: Cost of Gas Adjustment  
(COG) Rate 88 and Rate 99  
Case No. PU-10-\_\_\_\_

In accordance with North Dakota Century Code Section 49-05-05, Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., respectfully submits an original and seven (7) copies of a Cost of Gas (COG) change pursuant to the terms of Rates 88 and 99.

Attachment A is the Rate Summary Sheet (84<sup>th</sup> Revised Sheet No. 3) showing the proposed natural gas and propane rates, to be effective with service rendered April 1, 2010.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased \$0.472 per dk since the last filing due to a decrease in the overall market price of gas. Attachment B explains the reasons for the decrease in the market price of gas. There has also been a change in pipeline rates, as shown on Attachment C, decreasing the cost of gas \$0.053 per dk.

The COG tariff sheet, Exhibit A page 1, summarizes the gas cost adjustment, calculated pursuant to the terms of Rate 88, and the surcharge adjustment and market based pricing differential provision that will apply during the month of April 2010.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of \$0.525 per dk for residential and firm general service customers, a decrease of \$0.522 per dk for small and large interruptible customers and a decrease of \$0.520 per dk for Air Force interruptible customers from the currently effective rates.

Exhibit B shows the calculation of the current gas cost adjustment that will be applicable to Montana-Dakota's customers for the month of April 2010. The average cost of gas for firm customers, adjusted for losses, is \$6.076.

Exhibit C shows the calculation of the return on storage inventory balances and prepaid demand and commodity balances using the calculation procedure set forth in Rate 88.

The overall rate of return of 8.791% was authorized by the Commission in Case No. PU-04-97.

Montana-Dakota will not seek a Cost of Gas – Propane (COG) adjustment change for the month of April 2010. The Purchased Propane Cost Adjustment tariff (Rate 99), Section 2(b) provides that "Montana-Dakota shall file an adjustment to reflect changes in its average cost of propane supply only when the amount of such adjustment is at least 10 (ten) cents per dk." The COG adjustment for the month of April 2010 results in a change of less than 10 cents per dk, and therefore, in accordance with the authorized tariff, Montana-Dakota will not seek a purchased propane cost adjustment change.

The proposed adjustment, calculated in accordance with Rate 88, will amount to a decrease of approximately \$577,100 for natural gas customers during the month of April 2010. All of Montana-Dakota's retail gas customers in North Dakota may be affected by this proposal. There were 92,275 natural gas customers in North Dakota as of February 28, 2010.

Please refer all inquiries regarding this filing to:

Ms. Rita A. Mulkern  
Regulatory Analysis Manager  
Montana-Dakota Utilities Co.  
400 North Fourth Street  
Bismarck, ND 58501

Also, please send copies of all written inquiries, correspondence and pleadings to:

Mr. Daniel S. Kuntz  
Associate General Counsel  
MDU Resources Group, Inc.  
P. O. Box 5650  
Bismarck, ND 58506-5650

Montana-Dakota submitted a check for the amount of \$1,200 in accordance with North Dakota Century Code Section 49-05-05 on January 9, 2009. This payment will cover the filing fee associated with this monthly COG.

Montana-Dakota respectfully requests that this filing be accepted as being in full compliance with the filing requirements of this Commission.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed stamped envelope.

Sincerely,

A handwritten signature in cursive script that reads "Donald R. Ball".

Donald R. Ball  
Vice President – Regulatory Affairs

Attachment

**Attachment A**

**Rate Summary Sheet  
(Proposed)**



# Montana-Dakota Utilities Co.

A Division of MDU Resources Group, Inc.  
 400 N 4th Street  
 Bismarck, ND 58501

## State of North Dakota Gas Rate Schedule

NDPSC Volume 7  
 84th Revised Sheet No. 3  
 Canceling 83rd Revised Sheet No. 3

### RATE SUMMARY SHEET

Page 1 of 2

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/ Dk
Residential Rate 60	4	\$0.30 per day	\$0.812	\$5.550	\$6.362
Air Force Rate 64	7				
Minot Air Force Base		\$1,000.00 per month			
PAR Site		\$135.00 per month			
Firm Service			\$0.138	\$5.550	\$5.688
Interruptible Service - PAR			\$0.120	\$4.973	\$5.093
Interruptible Service - MAFB			\$0.120	\$5.126	\$5.246
Firm General Service Rate 70	13				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day	\$0.597	\$5.550	\$6.147
Small Interruptible Gas Rate 71	14	\$100.00 per month	(Maximum) \$0.871	\$4.973	(Maximum) \$5.844
Optional Seasonal Gas Service Rate 72	15				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day			
Winter Gas Usage			\$0.597	\$5.642	\$6.239
Summer Gas Usage			\$0.597	\$4.683	\$5.280
Transportation Service	24				
Small Interruptible Rate 81		\$150.00 per month			
Maximum			\$0.427		
Minimum			\$0.102		
Fuel Charge				\$0.023	
Large Interruptible Rate 82		\$725.00 per month			
Maximum			\$0.298		
Minimum			\$0.061		
Fuel Charge				\$0.023	
Large Interruptible Gas Rate 85	27	\$675.00 per month	(Maximum) \$0.719	\$4.973	(Maximum) \$5.692
Residential Propane Rate 90	32	\$0.30 per day	\$0.812	\$15.909	\$16.721
Firm General Propane Rate 92	34				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day	\$0.597	\$15.909	\$16.506

Date Filed: March 10, 2010

Effective Date:

Issued By: Donald R. Ball  
 Vice President - Regulatory Affairs

Case No.:

**Montana-Dakota Utilities Co.  
Market Conditions for Regional Natural Gas**

**April 2010**

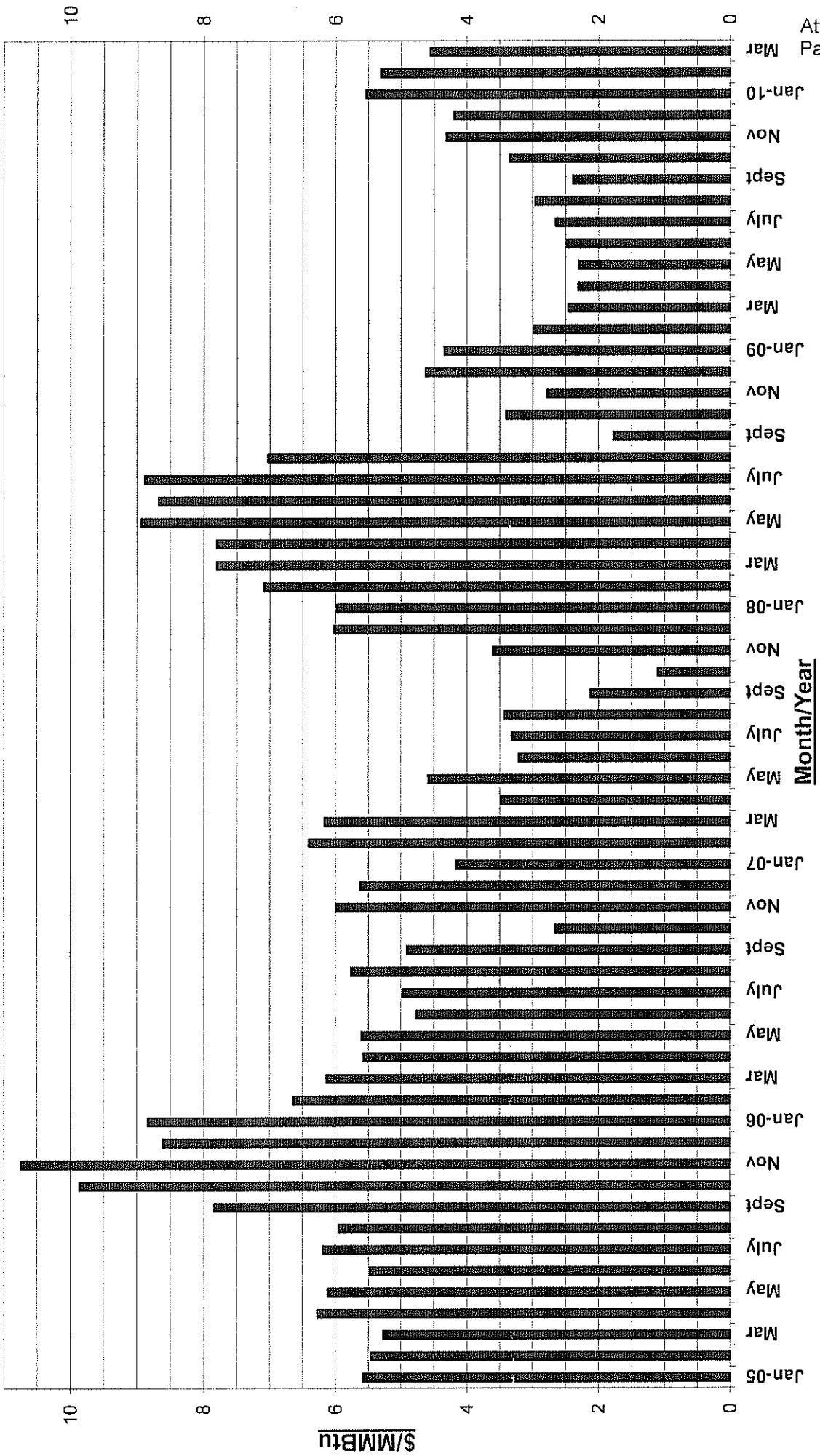
The established monthly price for the Rocky Mountain CIG Index decreased from the previous month. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices paid by willing sellers and buyers of quantities of gas in that region. That price is most reflective of natural gas prices in the Rocky Mountain region and indicative of a majority of the supplies Montana-Dakota purchases for its requirements.

Increased volumes of liquefied natural gas and gas imported from Canada along with the continued strong domestic supply of gas likely contributed to the decrease in the index prices. The Energy Information Administration (EIA) reported storage levels nationwide as of February 26, 2010 are 1.2 percent above the five-year average and 3.9 percent below last year's balance.

The EIA provides various publications on energy issues. The information is available on their website: <http://www.eia.doe.gov>.

The March Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 14.

# CIG Rocky Mountains Index Monthly Gas Prices 2004-2010YTD



From Inside F.E.R.C.'s Gas Market Report  
Annual Averages: - 2008-\$6.24; 2009-\$3.07; 2010YTD - \$5.14



March 2010

## Short-Term Energy Outlook

March 9, 2010 Release

### Highlights

- Although spot crude oil prices continue to fluctuate on a daily basis, EIA's projections for West Texas Intermediate (WTI) crude oil spot prices have remained relatively stable over the last 4 *Outlooks*. EIA expects WTI prices to average above \$80 per barrel this spring, rising to an average of about \$82 per barrel by the end of the year and to \$85 per barrel by the end of 2011.
- Projected economic growth this year is higher in this forecast, with U.S. real gross domestic product (GDP) growing by 2.8 percent and world oil-consumption-weighted real GDP growing by 3.4 percent, compared with 2.3 percent and 2.7 percent growth, respectively, in last month's *Outlook*. The 2011 forecast for real GDP growth is relatively unchanged at 2.6 percent and 3.5 percent for the United States and the world, respectively.
- EIA forecasts that the annual average regular grade retail gasoline price will increase from \$2.35 per gallon in 2009 to \$2.84 in 2010 and to \$2.96 in 2011 because of the projected rising crude oil prices. Average U.S. pump prices likely will exceed \$3 per gallon at times during the forthcoming spring and summer driving season. Projected annual average retail diesel fuel prices are \$2.96 and \$3.14 per gallon, respectively, in 2010 and 2011.
- EIA expects this year's annual average natural gas Henry Hub spot price to be \$5.17 per million Btu (MMBtu), a \$1.22-per-MMBtu increase over the 2009 average. EIA projects price increases to continue in 2011, averaging \$5.65 per MMBtu for the year. Projected working gas inventories end the first quarter of 2010 at about 1,550 billion cubic feet (Bcf) compared with 1,644 Bcf in the previous *Outlook* because of colder-than-normal weather in February. Natural-gas-weighted heating degree-days were nearly 11 percent above the 30-year norm last month.

- The annual average residential electricity price changes only slightly over the forecast period, averaging 11.5 cents per kilowatthour (kWh) in both 2009 and 2010, and then rising to 11.6 cents per kWh in 2011.
- Carbon dioxide (CO<sub>2</sub>) emissions from fossil fuels, which declined by 6.4 percent in 2009, increase by 1.5 percent and 1.2 percent in 2010 and 2011, respectively, in the forecast as economic growth fuels higher energy consumption.

## Global Crude Oil and Liquid Fuels

*Crude Oil and Liquid Fuels Overview.* EIA's more optimistic updated expectation for global economic growth during 2010 drives the 2010 forecast for oil consumption growth upwards to 1.5 million barrels per day (bbl/d) from 1.2 million bbl/d in last month's *Outlook*. This increased growth in 2010 oil consumption supports a firming of crude oil prices at above \$80 per barrel this summer and accommodates a further drawdown of commercial oil inventories. While EIA has also reduced its projections for surplus production capacity in the Organization of the Petroleum Exporting Countries (OPEC), surplus capacity remains ample, dampening the likelihood of a large upward swing in prices.

*Global Crude Oil and Liquid Fuels Consumption.* As noted above, the upward adjustment of 0.3 million bbl/d in the 2010 forecast for global liquid fuels consumption growth in this *Outlook* is largely due to expectations for greater economic growth ([World Liquid Fuels Consumption Chart](#)). Most of the increased economic growth in 2010 is expected in the Asia-Pacific and Middle East regions, thus largely outside of the countries in the Organization for Economic Cooperation and Development (OECD). EIA's expectations for both economic and oil consumption growth in 2011 remain about the same as in the previous *Outlook*.

*Non-OPEC Supply.* Non-OPEC supply increased by 590,000 bbl/d in 2009, the largest annual increase since 2004. Non-OPEC supply is projected to increase by 550,000 bbl/d in 2010 before declining slightly in 2011, as declining production in mature areas more than offsets any new production growth. The largest source of supply growth in 2010 is the United States, followed by Brazil, Azerbaijan, and Kazakhstan. Further declines in mature fields in Mexico, the United Kingdom, and Norway are expected in 2010.

*OPEC Supply.* The forecast assumes that OPEC does not change its target production levels at its scheduled meeting in mid-March. Given expected oil demand growth in 2010, oil prices should continue to firm despite expected increases in both non-OPEC and OPEC production this year. EIA projects that OPEC production of crude oil and

non-crude petroleum liquids, the latter of which are not subject to OPEC production targets, will increase by about 0.4 and 0.6 million bbl/d each year, respectively, about the same as in the previous *Outlook*. Overall, EIA also projects a slight decrease in OPEC surplus crude oil production capacity from the previous *Outlook* ([OPEC Surplus Crude Oil Production Capacity Chart](#)).

**OECD Petroleum Inventories.** EIA has revised its estimate of OECD commercial oil inventories at the end of 2009 downwards to 2.67 billion barrels, equivalent to about 57 days of forward cover and about 63 million barrels more than the 5-year average for the corresponding time of year ([Days of Supply of OECD Commercial Stocks Chart](#)). OECD oil inventories are still projected to remain at the upper end of the historical range over the forecast period.

**Crude Oil Prices.** WTI crude oil spot prices averaged \$76.39 per barrel in February 2010, almost \$2 per barrel lower than the prior month's average and very near the \$76 per barrel forecast in last month's *Outlook*. Last month, the WTI spot price reached a low of \$71.15 on February 5 and peaked at \$80.04 on February 22. EIA expects WTI prices to average above \$80 per barrel this spring, rising to an average of about \$82 per barrel by the end of the year and to \$85 per barrel by the end of 2011 ([West Texas Intermediate Crude Oil Price Chart](#)).

Following a slight increase in expected WTI price volatility early in February, implied volatility trended lower through the rest of the month, continuing a trend begun in the fourth quarter of 2009. Over the 5-day period ending March 4, May 2010 WTI futures averaged \$80.21 per barrel. Over the same 5-day period, the lower and upper limits for the 95-percent confidence interval for May 2010 futures were \$65 and \$99 per barrel, respectively, based on the May 2010 implied volatility, calculated from New York Mercantile Exchange (NYMEX) near-the-money options on WTI futures (see [Energy Price Volatility and Forecast Uncertainty](#)).

One year ago, WTI delivered into Cushing, Oklahoma, in May 2009 averaged about \$45 per barrel and implied volatility, at 74 percent, was more than twice the rate now trading in the options markets. The 95-percent confidence interval for May 2009 WTI futures thus had lower and upper limits of \$28 and \$75 per barrel, respectively.

## U.S. Crude Oil and Liquid Fuels

**U.S. Liquid Fuels Consumption.** U.S. liquid fuels consumption declined by 810,000 bbl/d (4.2 percent) to 18.7 million bbl/d in 2009, the fourth consecutive annual decline ([U.S. Liquid Fuels Consumption Growth Chart](#)). Motor gasoline was the only major petroleum product whose annual consumption did not decline. Distillate fuel

consumption declined by 310,000 bbl/d (8.0 percent) in 2009, led by a sharp economy-related decline in transportation usage.

The economic recovery contributes to projected growth in total liquid fuels consumption of 200,000 bbl/d in 2010 and 210,000 bbl/d in 2011. Nevertheless, expected U.S. consumption in 2011 is lower than total consumption was in 1999 and is 1.7 million bbl/d lower than the highest level of annual consumption reached in 2005.

EIA projects gasoline consumption will begin to show modest, but consistent, increases over the previous year, growing by 60,000 bbl/d in 2010 and 70,000 bbl/d in 2011. Projected distillate fuel consumption begins showing year-over-year growth this month, with an increase in average annual consumption of 20,000 bbl/d and 90,000 bbl/d in 2010 and 2011, respectively. However, this forecast for recovery in distillate fuel consumption remains highly uncertain because of the continuing observed weak diesel fuel demand.

***U.S. Liquid Fuels Supply and Imports.*** Domestic crude oil production averaged 5.32 million bbl/d in 2009, up about 370,000 bbl/d from 2008 ([U.S. Crude Oil Production Chart](#)). Projected growth in domestic crude oil production is more moderate in 2010, increasing by about 210,000 bbl/d. Production growth in 2011 slows sharply to 20,000 bbl/d, as substantial declines in the Federal Gulf of Mexico and Alaska almost offset gains in lower-48 on-shore production.

Ethanol production continues to grow to meet the volume requirements of the Renewable Fuel Standard. Ethanol production, which averaged 700,000 bbl/d in 2009, increases to an average of 800,000 bbl/d in 2010 and 850,000 bbl/d in 2011 in the forecast.

The decline in liquid fuels consumption in 2009 along with growth in domestic crude oil and ethanol production led to a 1.4-million-bbl/d drop in total liquid fuel net imports (including both crude oil and refined products). EIA forecasts that total liquid fuel net imports will fall by 150,000 bbl/d in 2010 and then rise by 100,000 bbl/d in 2011.

***U.S. Petroleum Product Prices.*** Regular-grade gasoline prices averaged \$2.35 per gallon in 2009, increasing from an average of \$1.79 per gallon in January 2009 to \$2.61 per gallon in December. EIA expects these prices will average \$2.84 per gallon in 2010 and \$2.96 per gallon in 2011. Average regular-grade pump prices likely will exceed \$3 per gallon at times during the upcoming spring and summer and will easily pass that benchmark in high-cost regions, such as the West Coast. Due to forecast growth in

motor gasoline consumption, the difference between the average gasoline retail price and the average cost of crude oil increases slightly in both 2010 and 2011.

On-highway diesel fuel retail prices, which averaged \$2.46 per gallon in 2009, average \$2.96 per gallon in 2010 and \$3.14 in 2011 in this forecast. As with motor gasoline, the forecast recovery in the consumption of diesel fuel in the United States, as well as growth in distillate fuel usage outside the United States, slowly strengthens refining margins for distillate throughout the forecast period.

## Natural Gas

***U.S. Natural Gas Consumption.*** EIA expects total natural gas consumption to increase by 0.7 percent to 62.9 billion cubic feet per day (Bcf/d) in 2010 and decline by 0.4 percent in 2011 (Total U.S. Natural Gas Consumption Growth Chart). Cold weather drives this year's natural gas consumption increases. Total natural-gas-weighted heating degree-days during the first 2 months of this year were 5.5 percent above the 30-year normal level and the highest for the period since 2004.

The combination of frigid temperatures and electric space heating in the Southeast contributed not only to increases in residential and commercial sector natural gas consumption but also to very strong natural gas consumption in the electric power sector. Even with the assumption of near-normal weather in March, EIA expects first-quarter natural gas use in the electric power sector to increase by about 3 percent above the same period last year and about 17 percent above the previous 5-year average. This increase in first quarter 2010 electric power sector consumption has all but eliminated the projected 1.3-percent year-over-year decline in natural gas consumption for this sector in last month's *Outlook*.

The 2011 outlook for a small decline in total natural gas consumption reflects the projected return to near-normal weather, which is expected to reduce consumption in the residential, commercial, and electric power sectors. Continued economic recovery contributes to a projected 2.1-percent increase in natural gas consumption in the industrial sector.

***U.S. Natural Gas Production and Imports.*** EIA expects total marketed natural gas production to decline by 2.7 percent to 58.7 Bcf/d in 2010 and increase by 1.1 percent in 2011. The number of working natural gas rigs has been increasing this year in response to higher prices in both the spot and forward markets. According to Smith International, natural gas rigs have increased by more than 17 percent, or by nearly 140, since the start of this year. There are currently almost 570 working horizontal rigs, a new record. EIA still anticipates a decline in 2010 production because of the lag

time arising from low drilling rates last year and steep decline rates associated with newly-drilled wells. However, continued recovery of drilling rig activity, increasing drilling efficiency, and the potential for higher production rates from shale gas wells could lead to higher-than-expected production this year and next.

EIA expects U.S. net imports to be slightly higher in 2010 as a projected decline in pipeline imports is offset by lower exports and higher imports of liquefied natural gas (LNG). While cold weather across the northern hemisphere has helped absorb some of the new LNG supply that has recently come on-stream, U.S. LNG imports are forecast to increase by nearly 0.8 Bcf/d over last year in the first quarter 2010. For 2010 as a whole, U.S. LNG imports are forecast to increase by about 45 percent (or 0.56 Bcf/d). As global LNG demand and import capacity expand next year, EIA expects U.S. LNG imports to show little year-over-year growth in 2011.

***U.S. Natural Gas Inventories.*** On February 26, 2010, working natural gas in storage was 1,737 Bcf (U.S. Working Natural Gas in Storage Chart), 21 Bcf above the previous 5-year average (2005–2009) and 71 Bcf below the level during the corresponding week last year. Persistent cold weather so far this year has taken a toll on inventories. The estimated total inventory withdrawal in January and February is 1,406 Bcf. The 5-year average withdrawal for these 2 months is 1,159 Bcf. EIA now expects working natural gas inventories to finish the first quarter of 2010 at around 1,549 Bcf, or about 3.5 percent above the previous 5-year average. In addition, resilient domestic production and higher U.S. LNG imports contribute to a projected end-of-October 2010 inventory that remains above the previous 5-year average.

***U.S. Natural Gas Prices.*** The Henry Hub spot price averaged \$5.32 per MMBtu in February, \$0.51 per MMBtu lower than the average spot price in January and \$0.14 per MMBtu lower than the forecast for February in last month's Outlook ([Henry Hub Natural Gas Price Chart](#)). Historically, colder-than-normal weather and correspondingly high demand has contributed to large storage withdrawals and elevated prices during the winter. For example, similar natural-gas-weighted heating degree-days and working natural gas storage withdrawals were recorded in January and February of this year and in 2003. While the cold weather in 2003 contributed to a 63-percent increase in the monthly average spot price from December 2002 to February 2003, the monthly average spot price in February 2010 was virtually unchanged from the average price in December 2009.

Much of the subdued price action this winter is attributable to the level of, as opposed to the change in, working inventories. By the end of February 2003, working stocks stood at 851 Bcf compared with an estimated 1,729 Bcf this February. Prices may strengthen slightly in the coming months as demand to rebuild natural gas in storage

from risk-averse local distribution companies begins. However, the potential for higher domestic production, increasing LNG supply, and limited consumption growth all reduce the possibility of sustained high prices as inventories are replenished over the next several months. The Henry Hub spot price forecast averages \$5.17 per MMBtu in 2010 and \$5.65 per MMBtu in 2011.

Volatility in the April and May 2010 futures and options markets trended lower over the last month. For the 5-day period ended March 4, May futures averaged \$4.77 per MMBtu, while the lower and upper limits of the 95-percent confidence interval calculated based on the implied volatility calculated from near-the-money options were \$3.57 and \$6.39 per MMBtu, respectively. A year earlier, natural gas delivered to the Henry Hub in May 2009 was trading at \$4.30 per MMBtu, with lower and upper limit for the 95-percent confidence interval calculated based on implied volatility of \$2.80 and \$6.60 per MMBtu, respectively.

## Electricity

***U.S. Electricity Consumption.*** EIA's assumption of 5.5 percent growth in manufacturing output during 2010 translates to an expected growth in electricity sales to the industrial sector of about 1 percent. EIA forecasts electricity sales to the residential sector to grow by 3.5 percent during 2010 since summer temperatures this year are expected to return to their normal levels after a relatively cool summer last year. Total consumption of electricity across all sectors is expected to grow by 2.0 percent during 2010 and by 1.5 percent next year ([U.S. Total Electricity Consumption Chart](#)).

***U.S. Electricity Generation.*** Natural gas generation during January and February was estimated to be about 10 percent higher than the same months last year because of the cold weather experienced in the South. This higher-than-expected level of natural gas generation during the early part of this year will pull up the projected 2010 annual growth rate to 0.6 percent, in contrast to the relatively flat growth projected in last month's *Outlook*.

***U.S. Electricity Retail Prices.*** The estimated average U.S. residential electricity price during 2009 was about 11.5 cents per kWh. EIA projects U.S. residential electricity prices will be about the same in 2010, followed by an increase of 1.4 percent in 2011 resulting primarily from higher natural gas generation fuel costs ([U.S. Residential Electricity Prices Chart](#)).

## Coal

**U.S. Coal Consumption.** Anticipated increases in electricity demand and higher natural gas prices will contribute to modest growth in coal-fired generation in 2010 and 2011. Forecast coal consumption in the electric power sector increases by about 3 percent in 2010, though staying under 1 billion short tons. EIA projects coal consumption in the electric power sector will increase by 1.6 percent in 2011, but remain below the 1-billion-short-ton level for the third consecutive year ([U.S. Coal Consumption Growth Chart](#)).

**U.S. Coal Supply.** EIA estimates that 2009 coal production fell by nearly 8 percent in response to lower U.S. coal consumption, fewer exports, and higher coal inventories. Production declines by an additional 7 percent in 2010 in this forecast despite increases in domestic consumption and exports. The balance between production and consumption is satisfied through significant reductions in end-user (secondary) inventories. EIA projects a 7-percent increase in coal production in 2011 to meet continued growth in coal consumption and exports as existing inventories are reduced ([U.S. Annual Coal Production Chart](#)).

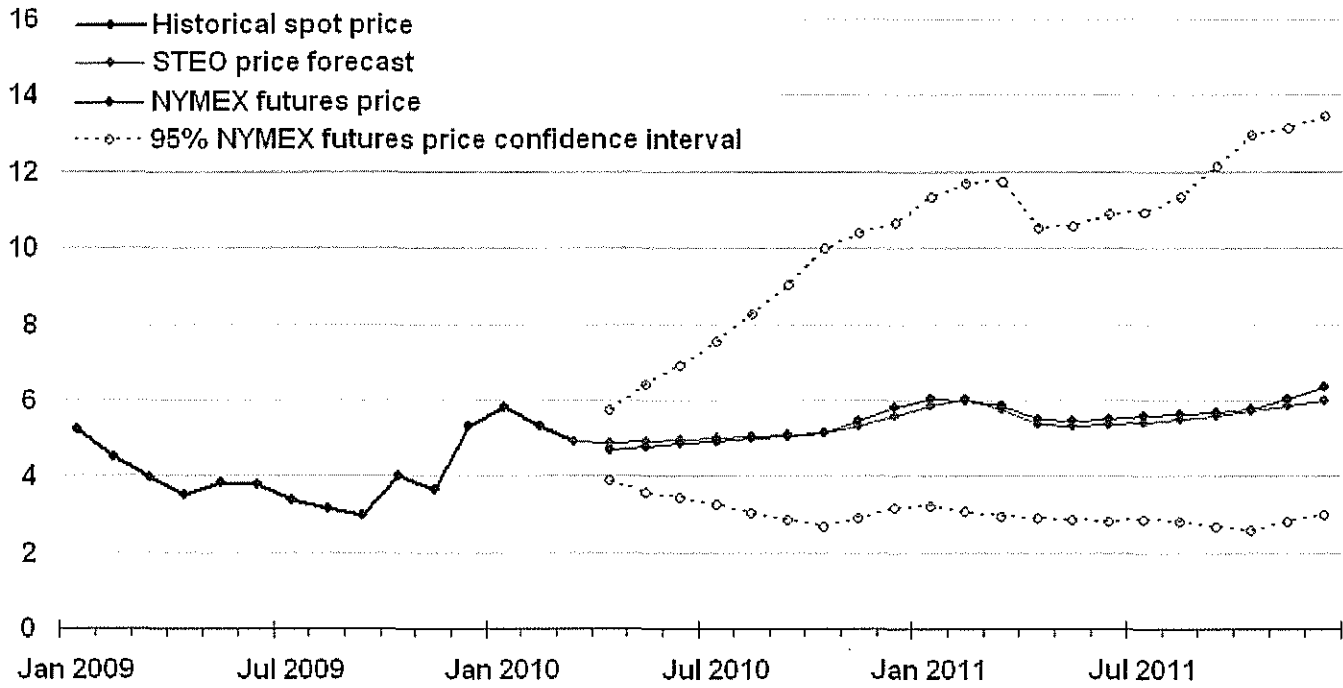
**U.S. Coal Prices.** EIA estimates that the 2009 delivered electric-power-sector coal price increased by nearly 7 percent in 2009 despite decreases in spot coal prices, lower prices for other fossil fuels, and declines in coal-fired electricity generation. This higher cost of delivered coal reflects the impact of longer-term power-sector coal contracts that were initiated during a period of high prices for all fuels. The projected electric-power-sector delivered coal price falls by almost 6 percent to average \$2.08 per MMBtu in 2010 and declines by an additional 2.4 percent in 2011.

## U.S. Carbon Dioxide Emissions

Projected improvements in the economy contribute to an expected 1.5-percent increase in CO<sub>2</sub> emissions in 2010 ([U.S. Carbon Dioxide Emissions Growth Chart](#)). Increased use of coal in the electric power sector and continued economic growth, combined with the expansion of transportation-related petroleum consumption, lead to a 1.2-percent increase in CO<sub>2</sub> emissions in 2011. However, even with increases in 2010 and 2011, projected CO<sub>2</sub> emissions in 2011 are lower than annual emissions from 1999 through 2008.

# Henry Hub Natural Gas Price

dollars per million btu



*Note: Confidence interval derived from options market information from 5 trading days ending March 4, 2010*

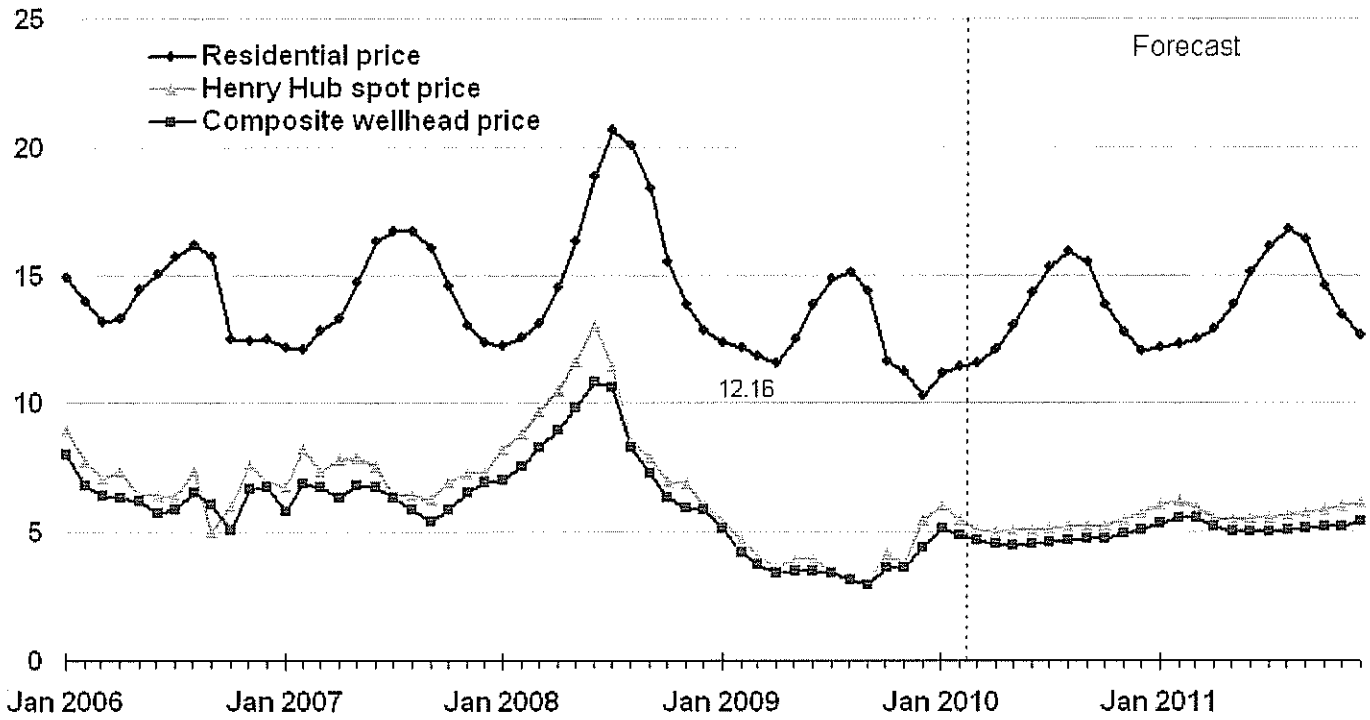
*Intervals not calculated for months with sparse trading in "close-to-the-money" options contracts*

Source: Short-Term Energy Outlook, March 2010; Reuters News Service; and CME Group



# Natural Gas Prices

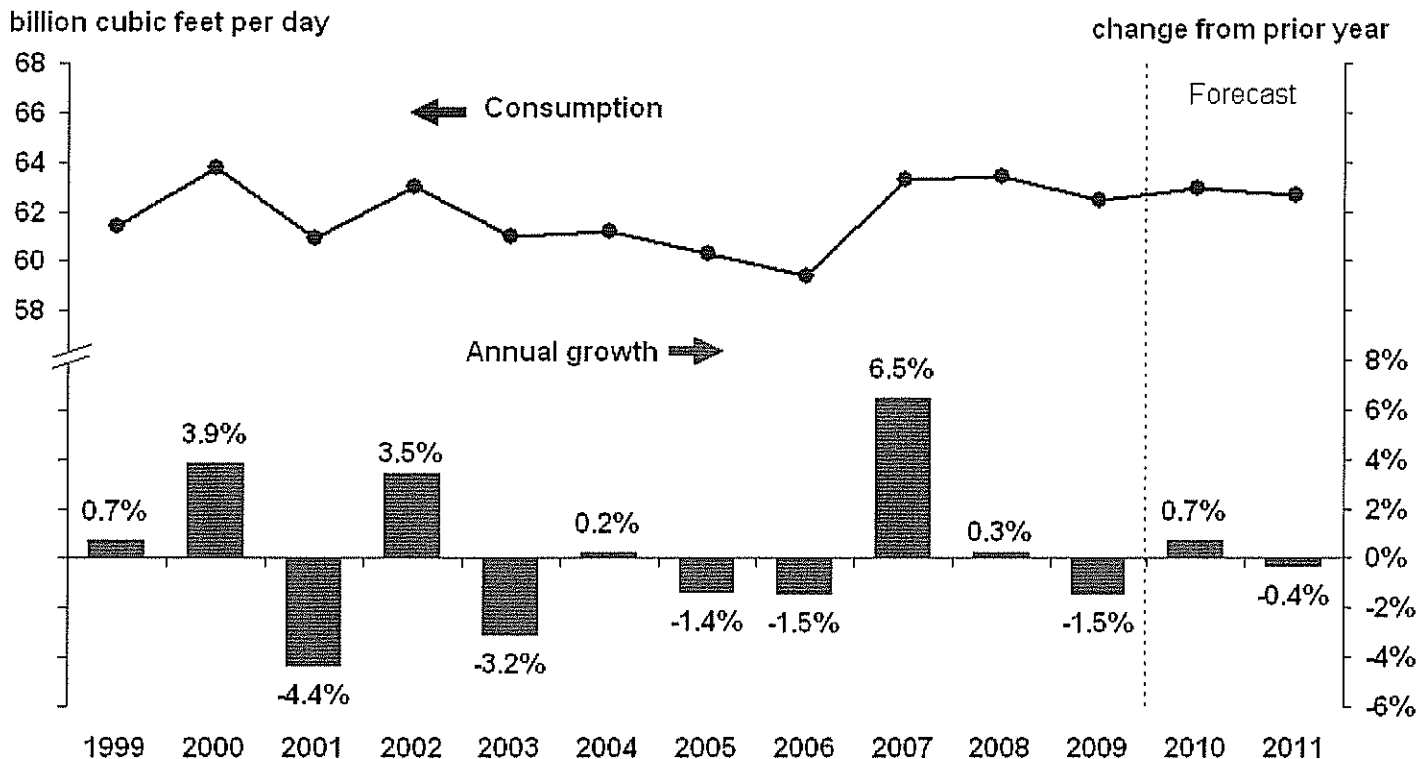
dollars per thousand cubic feet



Source: Short-Term Energy Outlook, March 2010; Reuters News Service



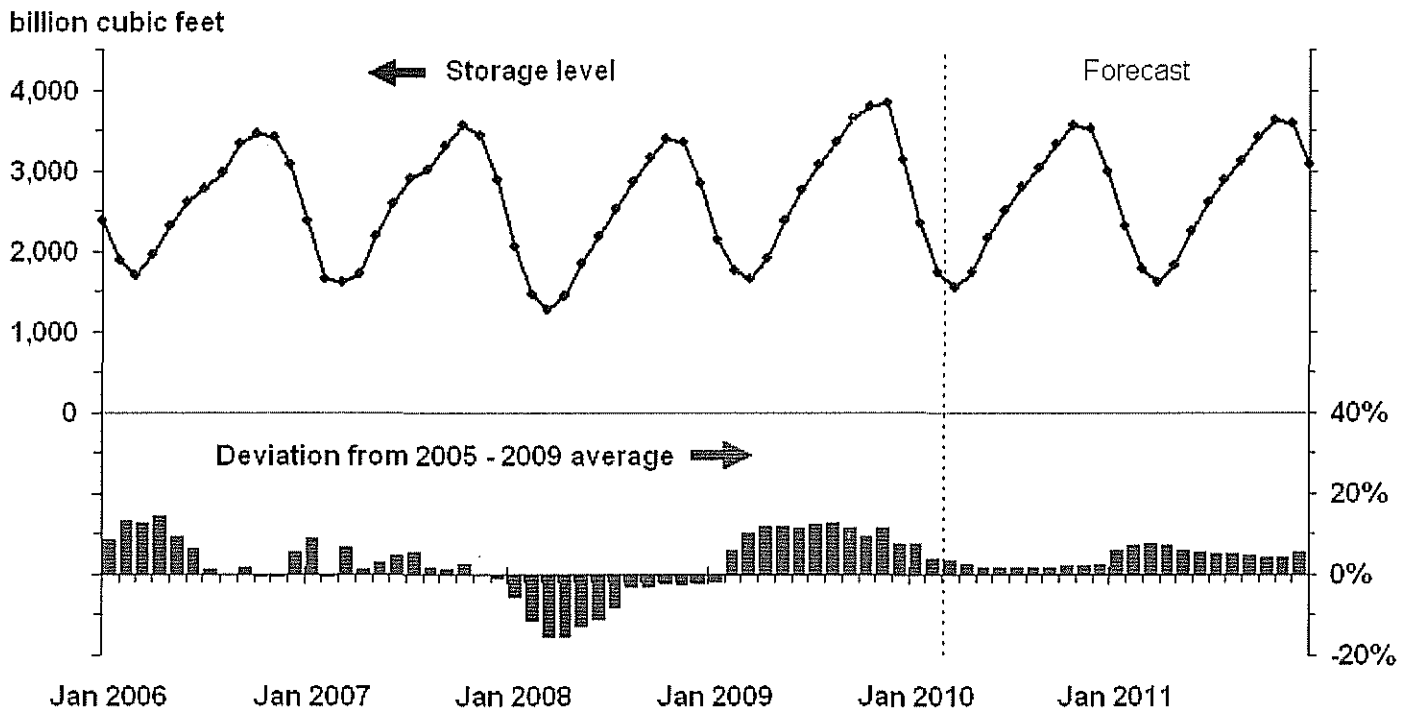
# U.S. Total Natural Gas Consumption



Source: Short-Term Energy Outlook, March 2010



# U.S. Working Natural Gas in Storage



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2005 - Dec. 2009

Source: Short-Term Energy Outlook, March 2010



**Montana-Dakota Utilities Co.  
Pipeline Rate Changes Since Last COG  
North Dakota**

**Williston Basin Interstate Pipeline Company Docket No. RP10- 439-000**

On March 1, 2010, Williston Basin filed its semi-annual fuel and electric power reimbursement adjustment with the FERC in Docket No. RP10-439-000, reflecting revisions to the fuel and electric power components of Williston Basin's transportation and storage rates to be effective April 1, 2010.

Approximate impact on Montana-Dakota's cost of gas – (5.3) cents per dk

MONTANA-DAKOTA UTILITIES CO.  
COST OF GAS TARIFF SHEET  
NORTH DAKOTA GAS  
EFFECTIVE APRIL 2010

	Firm			
	Residential & General Service	Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
<b><u>Gas Cost Adjustment:</u></b>				
Gas Cost Level (Exhibit B)	\$6.076	\$6.168	\$5.125	\$5.102
Prior Gas Cost	6.601	6.691	5.647	5.622
Current Gas Cost Adjustment	(\$0.525)	(\$0.523)	(\$0.522)	(\$0.520)
<b><u>Surcharge Adjustment:</u></b>				
Current Adjustment	(\$0.515)	(\$0.515)	(\$0.152)	\$0.024
Prior Adjustment	(0.515)	(0.515)	(0.152)	0.024
Change in Surcharge Adjustment	\$0.000	\$0.000	\$0.000	\$0.000
<b><u>Market Based Pricing Differential</u></b>				
Current Adjustment	(\$0.011)	(\$0.011)	\$0.000	\$0.000
Prior Adjustment	(0.011)	(0.011)	0.000	0.000
Change in Margin Sharing Provision	\$0.000	\$0.000	\$0.000	\$0.000
<b>Net Increase (Decrease) in Gas Costs</b>	<b><u>(\$0.525)</u></b>	<b><u>(\$0.523)</u></b>	<b><u>(\$0.522)</u></b>	<b><u>(\$0.520)</u></b>
Gas Cost Level	\$6.076	\$6.168	\$5.125	\$5.102
Plus: Surcharge	(0.515)	(0.515)	(0.152)	0.024
Total Gas Cost Level in Tariff Rates	<b><u>\$5.561</u></b>	<b><u>\$5.653</u></b>	<b><u>\$4.973</u></b>	<b><u>\$5.126</u></b>

**MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
RESIDENTIAL AND GENERAL SERVICE  
EFFECTIVE APRIL 2010**

	Amount
Total Gas Costs 1/	\$81,186,244
Residential and General Service dk Requirements 2/	13,421,483
Average Cost of Gas per dk	\$6.049
Average Cost of Gas as Adjusted for Losses @ 99.55%	6.076
Less: Gas Cost Level in Rates 3/	6.601
<b>Current Gas Cost Adjustment</b>	<b>(\$0.525)</b>

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -14 for currently effective pipeline rates. Also includes a return on prepaid demand, commodity and cycle storage balances as shown on Exhibit C.

2/ Normalized dk sales for the twelve months ended January 31, 2010, adjusted for losses at .45%

3/ Gas Cost Level in Current Tariff Rates Case No. PU-10-8:

Cost of Purchased Gas	\$6.571
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$6.601

**MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
OPTIONAL SEASONAL - RATE 72  
EFFECTIVE APRIL 2010**

<u>Summer - June - September</u>	
Total Gas Costs 1/	\$81,186,244
Less: Annual MDDQ Costs 1/	<u>11,587,067</u>
Total Gas Costs excluding MDDQ	\$69,599,177
Firm Service Requirements 1/	13,421,483
Other Gas Costs per Dk (excluding MDDQ)	\$5.186
Summer Seasonal Rate, adjusted for losses 2/	5.209
<u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$11,587,067
Winter Firm Service Requirements	12,150,977
MDDQ Costs per Winter Dk	\$0.954
Add: Other Gas Costs per Dk	<u>5.186</u>
Winter Seasonal Rate	6.140
Winter Seasonal Rate, adjusted for losses 2/	\$6.168
Less: Gas Cost Level in Rates 3/	<u>6.691</u>
<b>Current Gas Cost Adjustment</b>	<b><u><u>(\$0.523)</u></u></b>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-10-8:

	<u>Summer</u>	<u>Winter</u>
Cost of Purchased Gas	\$5.712	\$6.661
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	\$5.738	\$6.691

**MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
INTERRUPTIBLE  
EFFECTIVE APRIL 2010**

	Amount
Total Gas Costs 1/	\$17,869,433
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$5.102
Average Cost of Gas as Adjusted for Losses @ 99.55%	5.125
Less: Gas Cost Level in Rates 2/	5.647
<b>Current Gas Cost Adjustment</b>	<b>(\$0.522)</b>

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -14 for currently effective pipeline rates. Also includes a return on prepaid demand, commodity and cycle storage balances as shown on Exhibit C.

2/ Gas Cost Level in Current Tariff Rates Case No. PU-10-8:

Cost of Purchased Gas	\$5.622
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$5.647

MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
AIR FORCE INTERRUPTIBLE  
EFFECTIVE APRIL 2010

	<u>Amount</u>
Total Gas Costs 1/	\$4,489,357
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	\$5.102
Less: Gas Cost Level in Rates 2/	<u>5.622</u>
<b>Current Gas Cost Adjustment</b>	<b><u><u>(\$0.520)</u></u></b>

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -14 for currently effective pipeline rates. Also includes a return on prepaid demand, commodity and cycle storage balances as shown on Exhibit C, allocated to Air Force interruptible on MDDQ.

2/ Gas Cost Level in Current Tariff Rates Case No. PU-10-8:  
Cost of Purchased Gas \$5.622

**Montana-Dakota Utilities Co.  
Schedule of Applicable Effective Pipeline Rates  
April 2010 PGA**

Williston Basin Interstate Pipeline Company - Exhibit B, pages 6 - 8 for Schedules FT-1, FTN-1, and FS-1.

Northern Border Pipeline Company – Exhibit B, pages 9-10 for Schedule T-1.

Foothills Pipe Lines, Ltd. - Billed on a cost of service basis so there are no tariff sheets.

NOVA Gas Transmission – Exhibit B, page 11 for Schedule FT-D.

NorthWestern Energy – Exhibit B, page 12 for Schedule T-FTG-1.

South Dakota Intrastate Pipeline – Exhibit B, page 13 for Rate 1.

SourceGas Distribution LLC – Exhibit B, Page 14 for Schedule TC.

NOTICE OF CURRENTLY EFFECTIVE RATES

(ALL RATES ARE STATED IN CENTS PER DEKATHERM OR EQUIVALENT DEKATHERM AS INDICATED)

RATE SCHEDULE	UNIT	BASE TARIFF RATE	ACA SURCHARGE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
-----						
RATE SCHEDULE FT-1						
-----						
RESERVATION CHARGE						
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)						
MAXIMUM	RATE PER EQV. DKT PER MO.	737.928	N.A.	N.A.	N.A.	737.928
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	N.A.	0.000
COMMODITY CHARGE						
MAXIMUM A/B/	RATE PER DKT	3.120	0.190	N.A.	N.A.	3.310
MINIMUM A/B/	RATE PER DKT	3.120	0.190	N.A.	N.A.	3.310
SCHEDULED OVERRUN CHARGE						
MAXIMUM A/B/	RATE PER DKT	30.884	0.190	N.A.	N.A.	31.074
MINIMUM A/B/	RATE PER DKT	3.120	0.190	N.A.	N.A.	3.310

- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR TRANSPORTATION FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 1.823%, CONSISTING OF 2.284% FOR THE CURRENT PERCENTAGE AND (0.461%) FOR THE DEFERRAL PERCENTAGE. THIS PERCENTAGE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.
- B/ SHIPPER MUST REIMBURSE TRANSPORTER FOR ELECTRIC POWER USED FOR TRANSPORTATION. THE APPLICABLE RATE IS 0.271 CENTS, CONSISTING OF 0.283 CENTS FOR THE CURRENT RATE AND (0.012) CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.

NOTICE OF CURRENTLY EFFECTIVE RATES

(ALL RATES ARE STATED IN CENTS PER DEKATHERM OR EQUIVALENT DEKATHERM AS INDICATED)

RATE SCHEDULE	UNIT	BASE TARIFF RATE	ACA SURCHARGE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
-----						
RATE SCHEDULE FTN-1						
-----						
RESERVATION CHARGE						
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)						
MAXIMUM	RATE PER EQV. DKT PER MO.	47.491	N.A.	N.A.	N.A.	47.491
MINIMUM	RATE PER EQV. DKT PER MO.	1.589	N.A.	N.A.	N.A.	1.589

Issued by: Keith A. Tiggelaar - Director of Regulatory Affairs

Issued on: May 19, 2005

Effective on: April 19, 2005

Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. RP00-107, et al., issued April 19, 2005

NOTICE OF CURRENTLY EFFECTIVE RATES

(ALL RATES ARE STATED IN CENTS PER DEKATHERM OR EQUIVALENT DEKATHERM AS INDICATED)

RATE SCHEDULE	UNIT	BASE TARIFF RATE	ACA SURCHARGE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
-----						
RATE SCHEDULE FS-1						
-----						
CAPACITY RESERVATION						
MAXIMUM	RATE PER EQV. DKT PER MO.	2.102	N.A.	N.A.	N.A.	2.102
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	N.A.	0.000
CAPACITY DELIVERABILITY						
MAXIMUM	RATE PER EQV. DKT PER MO.	190.602	N.A.	N.A.	N.A.	190.602
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	N.A.	0.000
INJECTION						
MAXIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
WITHDRAWAL						
MAXIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
SCHEDULED OVERRUN CHARGE						
INJECTION						
MAXIMUM A/B/	RATE PER DKT	23.920	N.A.	N.A.	N.A.	23.920
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
WITHDRAWAL						
MAXIMUM A/B/	RATE PER DKT	23.920	N.A.	N.A.	N.A.	23.920
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888

- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR STORAGE FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 0.437%, CONSISTING OF 0.603% FOR THE CURRENT PERCENTAGE AND (0.166%) FOR THE DEFERRAL PERCENTAGE. THIS PERCENTAGE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.
- B/ SHIPPER MUST REIMBURSE TRANSPORTER FOR ELECTRIC POWER USED FOR STORAGE. THE APPLICABLE RATE IS (0.164) CENTS, CONSISTING OF 0.000 CENTS FOR THE CURRENT RATE AND (0.164) CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.

Northern Border Pipeline Company  
FERC Gas Tariff  
First Revised Volume No. 1

Seventh Revised Sheet No. 98  
Superseding  
Sixth Revised Sheet No. 98

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STATEMENT OF RATES

2/ 3/

Rate Schedule -----	Long-Term Base Tariff Rate (per 100 Dth-Miles) 1/ -----
T-1 and T-1B	
Daily Reservation Rate - Port of Morgan, MT to Ventura, IA	
Maximum	\$0.0321
Minimum	\$0.0000
Daily Reservation Rate - Ventura, IA to North Hayden, IN	
Maximum	\$0.0345
Minimum	\$0.0000
Commodity Rate - Port of Morgan, MT to North Hayden, IN	
Maximum	\$0.0004
Minimum	\$0.0004

- 1/ Applicable to any Rate Schedule T-1 U.S. Shippers Service Agreement or any Rate Schedule T-1B Service Agreement with a primary term of at least twelve consecutive months.
- 2/ The Settlement Base Rates, pursuant to the Stipulation at Docket No. RP06-72-000, et al., remain in effect until such rates are superseded by new base rates placed into effect consistent with the provisions of the Stipulation.
- 3/ Rates on this sheet are subject to the revenue retrieval provision pursuant to Article X of the Stipulation at Docket No. RP06-72-000, et al.

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Issued by: Raymond D. Neppl, Vice President

Issued on: November 21, 2006

Effective on: January 1, 2007

Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. RP06-72-000, issued November 21, 2006, 17 FERC ¶ 61,217

Northern Border Pipeline Company  
FERC Gas Tariff  
First Revised Volume No. 1

Fourteenth Revised Sheet No. 99  
Superseding  
Thirteenth Revised Sheet No. 99

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STATEMENT OF RATES

	Commodity Rate -----
Annual Charge Adjustment (ACA) Rate (per Dekatherm) 1/	\$0.0019
Compressor Usage Surcharge (per 100 Dekatherm-miles) 2/	\$0.0026

1/ In accordance with the Commission's regulations, the authorized FERC unit charge per dekatherm is applied to physical transportation deliveries and is applicable to all transportation rate schedules. Pursuant to Section 16 of the General Terms and Conditions herein, the ACA is effectively charged at a rate of \$0.0002 per 100 Dekatherm-miles.

2/ Rate is charged in accordance with Section 45 of the General Terms and Conditions.

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Issued by: Bambi L. Heckerman, Manager, Regulatory Affairs

Issued on: August 21, 2009

Effective on: October 1, 2009

NOVA Gas Transmission Ltd.

Table of Rates, Tolls and Charges

TABLE OF RATES, TOLLS & CHARGES

Service	Rates, Tolls and Charges		
1. Rate Schedule FT-R	Refer to Attachment "1" for applicable FT-R Demand Rate per month & Surcharge for each Receipt Point Average Firm Service Receipt Price (AFSRP) \$213.83/10 <sup>3</sup> m <sup>3</sup>		
2. Rate Schedule FT-RN	Refer to Attachment "1" for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point		
3. Rate Schedule FT-D	FT-D Demand Rate per month \$ 5.66/GJ		
4. Rate Schedule STFT	STFT Bid Price. Minimum bid of 100% of FT-D Demand Rate		
5. Rate Schedule FT-DW	FT-DW Bid Price. Minimum bid of 125% of FT-D Demand Rate		
6. Rate Schedule FT-A	FT-A Commodity Rate \$ 0.55/10 <sup>3</sup> m <sup>3</sup>		
7. Rate Schedule FT-P	Refer to Attachment "2" for applicable FT-P Demand Rate per month		
8. Rate Schedule LRS	<u>Contract Term</u>	<u>Effective LRS Rate (\$/10<sup>3</sup>m<sup>3</sup>/day)</u>	
	1-5 years	10.43	
	6-10 years	8.72	
	15 years	7.82	
	20 years	6.94	
9. Rate Schedule LRS-2	LRS-2 Rate per month \$50,000		
10. Rate Schedule LRS-3	LRS-3 Demand Rate per month \$129.55/10 <sup>3</sup> m <sup>3</sup>		
11. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate & Surcharge for each Receipt Point		
12. Rate Schedule IT-D	IT-D Rate \$ 0.2045/GJ		
13. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service		
14. Rate Schedule PT	<u>Schedule No</u>	<u>PT Rate</u>	<u>PT Gas Rate</u>
	9006-01000-0	\$ 60.50/d	1.0 10 <sup>3</sup> m <sup>3</sup> /d
	9009-01001-1	\$660.00/d	50.0 10 <sup>3</sup> m <sup>3</sup> /d
15. Rate Schedule OS	<u>Schedule No.</u>	<u>Charge</u>	
	2010418777	\$ 209.00 / month	
	2010416547	\$ 24.00 / month	
	2010416549	\$ 63.00 / month	
	2010416543	\$ 7.00 / month	
	2010416546	\$ 5.00 / month	
	2010416548	\$ 1.00 / month	
	2010416540	\$ 42.00 / month	
	2010416550	\$ 96.00 / month	
	2010418778	\$ 350.00 / month	
	2010416545	\$ 1,688.00 / month	
	2010418000	\$ 151.00 / month	
	2010416551	\$ 46.00 / month	
	2010417322	\$ 153.00 / month	
	2010416544	\$ 79.00 / month	
	2010416541	\$ 209.00 / month	
2003004522	\$ 83,333.00 / month		
16. Rate Schedule CO <sub>2</sub>	<u>Tier</u>	<u>CO<sub>2</sub> Rate (\$/10<sup>3</sup>m<sup>3</sup>)</u>	
	1	520.03	
	2	411.79	
	3	272.12	

Effective Date: January 1, 2010 (Amended March 1, 2010)

NATURAL GAS TARIFF

**NorthWestern**  
Energy

Canceling  $\frac{18^{th}}{17^{th}}$  Revised Revised Sheet No. 80.1  
Sheet No. 80.1

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT  
FIRM TRANSPORTATION NATURAL GAS SERVICE

**APPLICABILITY:** Applicable to Shippers for firm transportation service on the Utility Transmission System under the terms of a Firm Gas Transportation Service Agreement (Agreement) between the Utility Transportation Business Unit (Utility) and Shipper and as subject to Rate Schedule General Terms and Operating Conditions (Rate Schedule GTC-1).

**RATES:** Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour	Per Meter Charge	
5,001 to 10,000	\$ 100.85	(I)
10,001 to 30,000	\$ 145.05	(I)
>30,000	\$ 321.90	(I)

**PLUS:**

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for Maximum Daily Delivery Quantity (MDDQ)	\$ 8.248586 (I)
--	-----------------

Transmission Commodity Rate (Monthly Rate per Dkt):

Maximum	\$ 0.062506 (I)
Minimum	\$ 0.017935
GTAC Amortization	\$ (0.001275)
Balancing Penalty Rate	Higher of \$25.00 / Dkt. Or 150% of Market Price

**PLUS:**

**OTHER APPLICABLE CHARGES:** All charges contained on other applicable rate schedules approved by the Public Service Commission of Montana.

**GAS TRANSPORTATION ADJUSTMENT CLAUSE:** Pursuant to MPSC Order the above GTAC Amortization shall be in effect until the balance is extinguished.

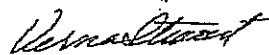
**MINIMUM BILL:** Per respective contracts.

(continued)

Staff Approved: February 22, 2010  
Docket No.: D2009.12.155  
Tariff Letter No. 165-G

Effective for service rendered on or after  
January 1, 2010

PUBLIC SERVICE COMMISSION

 Secretary

**GAS RATE SCHEDULE**

**South Dakota Intrastate Pipeline Company**  
1415 N. Airport Rd  
Pierre, SD 57501  
e Filed: January 24, 2001

SD P.U.C.            Section No. 3  
Original Sheet No. 1

Effective Date: January 10, 2001

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**TRANSPORTATION SERVICE    Rate 1**

Transportation rate is \$2.398 per dekatherm.

Issued By: Lisa A. Murphy, Vice President-Chief Financial Officer  
**STATE OF SOUTH DAKOTA**  
**GAS RATE SCHEDULE**

PUBLIC SERVICE COMMISSION OF WYOMING

SourceGas Distribution LLC

Wyo. P.S.C. Tariff No. 5  
First Revised Sheet No. 12  
Cancels Original Sheet No. 12

Statement of Firm and Interruptible Transportation Service Rates  
Applicable to Shippers Not Receiving  
Choice Gas Service  
Rate Schedule TC 1/  
Casper Division

<u>Division</u>	<u>Receipt Point</u>	<u>Delivery Point</u>	<u>Monthly Customer Charge</u>	<u>Maximum Transportation Charge 2/</u>	<u>Minimum Transportation Charge 2/</u>	<u>Fuel Reimbursement Quantity Percentage 3/</u>
TC (Casper)						
Firm						
Transportation	MLI	MLI	\$0.00	\$1.0551	\$0.0100	0.781%
	MLI	MLE	\$163.00	\$1.0551	\$0.0100	0.781%
	MLI	DSE	\$163.00	\$2.0988	\$0.0200	3.425%
Interruptible						
Transportation 4/	MLI	MLI	\$0.00	\$0.8439	\$0.0100	0.781%
	MLI	MLE	\$163.00	\$0.8439	\$0.0100	0.781%
Administrative						
Fee 5/			\$325.00			

- 1/ Casper Division service area is defined on Sheet Nos. 3 and 4 of this Tariff.
- 2/ All charges are per Dekatherm.
- 3/ For fuel, lost and unaccounted for gas, SourceGas shall be entitled to retain the stated percentage of all Dekatherms received for transportation, unless otherwise agreed in writing.
- 4/ Interruptible Transportation Service is not available to DSE customers. The Customer Charge will be charged only for those months gas actually flows.
- 5/ In addition to the transportation charges stated above, Shippers are responsible for the monthly administrative fee as stated, applicable to each meter located at the customer location. For Interruptible Transportation Shippers, the Administrative Fee will be charged only for those months gas actually flows. Firm Transportation Shippers will be charged each month, regardless of gas flow.

Abbreviations (as defined in the General Terms and Conditions of this Tariff):

MLI Mainline System Interconnect  
MLE Mainline System End-user  
DSE Distribution System End-user

Date Issued: June 8, 2007  
By: Bentley W. Breland

Date Effective: June 15, 2007  
Title: Senior Vice President

**MONTANA-DAKOTA UTILITIES CO.  
RETURN ON CYCLE STORAGE BALANCES  
AND PREPAID DEMAND AND COMMODITY BALANCES  
NORTH DAKOTA GAS  
EFFECTIVE APRIL 2010**

	General Service		
	Storage Balance 1/	Commodity Balance 2/	Prepaid Demand
October 2009	\$12,185,122	\$676,026	\$3,129,297
November	11,254,366	597,205	2,522,196
December	8,704,183	412,412	1,199,079
January 2010	3,383,952	215,680	(391,041)
February	(676,068)	48,961	(1,342,623)
March	(2,988,789)	(52,542)	(1,947,071)
April	(2,842,828)	(69,469)	(1,763,922)
May	(1,660,393)	(39,966)	(1,045,845)
June	539,282	28,642	(52,339)
July	4,025,110	142,424	989,367
August	8,082,932	276,066	2,010,616
September	11,717,292	607,168	2,815,929
October	13,464,499	647,565	3,070,039
13 month average	<u>\$5,014,512</u>	<u>\$268,475</u>	<u>\$707,206</u>
Rate of Return	8.791%	8.791%	8.791%
Return	\$440,826	\$23,602	\$62,170
Return Requirement	<u>\$607,208</u>	<u>\$32,510</u>	<u>\$85,635</u>

1/ Monthly balance from SENDOUT Model, allocated to North Dakota on ratio of storage capacity MDDQ.

2/ Monthly balance allocated to North Dakota on sales volumes.

**MONTANA-DAKOTA UTILITIES CO.  
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ACCOUNT BALANCE  
APPLICABLE TO NORTH DAKOTA  
FIRM**

	<u>(Over) Under Recovery</u>	<u>Refunds &amp; Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
<b>Balance @ July 31, 2009</b>									<b><u>(\$6,530,761)</u></b>
August	(\$284,184)	\$9,408 2/	(\$929)	(\$275,705)	261,090	\$0.845	\$220,621	(\$496,326)	(7,027,087)
September	1,597	0	(706)	891	256,293	0.845	216,567	(215,676)	(7,242,763)
October	122,909	0	(424)	122,485	583,825	(0.515)	149,323 3/	(26,838)	(7,269,601)
November	671,644	0	(304)	671,340	1,022,685	(0.515)	(526,683)	1,198,023	(6,071,578)
December	50,832	7,503 4/	(254)	58,081	1,808,016	(0.515)	(931,125)	989,206	(5,082,372)
January 2010	78,170	0	(255)	77,915	2,540,386	(0.515)	(1,308,299)	1,386,214	(3,696,158)
<b>Balance @ January 31, 2010</b>									<b><u>(\$3,696,158)</u></b>

1/ Interest calculated at 90 day Treasury Note rate.

2/ Prior period adjustment to correct the allocation between jurisdictions.

3/ Reflects 330,877 Dk @ \$0.845 and 252,948 Dk @ (\$0.515).

4/ Billing adjustment.

**MONTANA-DAKOTA UTILITIES CO.  
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ACCOUNT BALANCE  
APPLICABLE TO NORTH DAKOTA  
INTERRUPTIBLE**

	<u>(Over) Under Recovery</u>	<u>Refunds &amp; Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
<b>Balance @ July 31, 2009</b>									<b><u>(\$92,116)</u></b>
August	(\$16,499)	\$522 2/	(\$13)	(\$15,990)	25,403	\$0.349	\$8,865	(\$24,855)	(116,971)
September	3,789	0	(12)	3,777	27,818	0.349	9,709	(5,932)	(122,903)
October	(20,599)	0	(7)	(20,606)	32,507	0.349	11,344	(31,950)	(154,853)
November	55,639	0	(7)	55,632	70,459	(0.152)	(10,710)	66,342	(88,511)
December	39,061	0	(4)	39,057	88,074	(0.152)	(13,388)	52,445	(36,066)
January 2010	(69,893)	0	(2)	(69,895)	108,660	(0.152)	(16,516)	(53,379)	(89,445)
<b>Balance @ January 31, 2010</b>									<b><u>(\$89,445)</u></b>

1/ Interest calculated at 90 day Treasury Note rate.

2/ Prior period adjustment to correct the allocation between jurisdictions.

**MONTANA-DAKOTA UTILITIES CO.  
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ACCOUNT BALANCE  
APPLICABLE TO NORTH DAKOTA  
AIR FORCE**

	<u>(Over) Under Recovery</u>	<u>Refunds &amp; Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
<b>Balance @ July 31, 2009</b>									<b><u>\$14,785</u></b>
August	(\$15,035)	\$336 2/	\$2	(\$14,697)	7,141	\$0.167	\$1,193	(\$15,890)	(1,105)
September	877	0	0	877	6,410	0.167	1,070	(193)	(1,298)
October	(4,862)	0	0	(4,862)	7,589	0.167	1,267	(6,129)	(7,427)
November	23,780	0	0	23,780	37,871	0.024	909	22,871	15,444
December	19,124	0	1	19,125	42,502	0.024	1,020	18,105	33,549
January 2010	(53,605)	0	2	(53,603)	88,110	0.024	2,115	(55,718)	(22,169)
<b>Balance @ January 31, 2010</b>									<b><u>(\$22,169)</u></b>

1/ Interest calculated at 90 day Treasury Note rate.

2/ Prior period adjustment to correct the allocation between jurisdictions.